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SHALLOW GAS EVENTS

Gulf of Mexico OCS Region

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U.S. DEPARTMENT OF THE INTERIOR/MINERALS MANAGEMENT SERVICE

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SHALLOW GAS EVENTS

Prepared by the
MINERALS MANAGEMENT SERVICE
GULF OF MEXICO OCS REGION

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U.S. DEPARTMENT OF THE INTERIOR/MINERALS MANAGEMENT SERVICE

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ABSTRACT

Shallow gas accumulations have caused conditions hazardous to oil and gas drilling operations in the Outer Continental Shelf (OCS) of the Gulf of Mexico since 1958. The violent nature of these encounters has caused several fatalities, many injuries, pollution events, and drilling/production equipment losses amounting to hundreds of millions of dollars. As the search for oil and gas moves further into undeveloped areas of the OCS, encounters with shallow gas are expected to become increasingly numerous because of the greater accumulation of shallow gas in the more recent sediments.

All information available on drilling encounters with shallow gas on the Gulf of Mexico OCS has been accumulated and analyzed in this report. Similar causes for failure to maintain well control are categorized, and basic recommendations designed to eliminate repetition of these situations are given. Also, recommendations for equipment, methods, and procedures to be used for safer drilling in areas prone to have shallow gas accumulations are included in this report.

The information on the 27 shallow gas encounters in the Gulf of Mexico OCS discussed in this report was derived from accident reports and other reports filed by operators. In many cases, no official accident report was available and only handwritten accounts of telephone conversations concerning the encounter were available. A brief synopsis of each event is contained in the Appendix.

INTRODUCTION

The control of underground pressure is the most important single factor when planning and conducting drilling or production operations. Improper well planning and control procedures can result in the sudden, uncontrolled escape of hydrocarbons. Such an event is commonly referred to as a blowout. Blowouts are the most spectacular, expensive, and feared operational hazard. At best, they result in costly delays in drilling or production programs, but they may also lead to fires, explosions, casualties, serious property damage, and pollution.

A most difficult underground pressure to control is overpressured shallow gas. Drilling through such gaseous zones requires utmost caution. Because the hole is shallow, gas can reach the surface quickly with very little warning. A delicate drilling mud overbalance of the formation pressure is necessary to prevent a gas influx without fracturing near-surface formations. Protection against fracturing can be an increasingly difficult problem in deepwater drilling because the hydrostatic pressure exerted by the mud column is relatively greater than the decrease in pressure exerted by the overburden. A Louisiana State University (LSU) report explains this problem in detail.[1]

The best defense against shallow gas problems in these areas is to prevent the problem by properly selecting drill sites on the basis of expert interpretations of shallow geophysical and geologic data.

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[1] Final Report, Development of Improved Blowout Prevention Procedures for Deepwater Drilling Operations, LSU, Contract No. 14-08-0001-17225, Minerals Management Service, U.S. Department of the Interior.

AREAS OF CONCERN FOR SHALLOW GAS

Shallow gas was the cause of 24 of the 27 encounters discussed in this report. The other three encounters were caused by drilling into a producing well. Because the effects and methods of control are very similar to those caused by a shallow gas formations these incidents are included. Many shallow gas flows have been located in the High Island, South Marsh Island, and Eugene Island Areas and originated from accumulations found in the tertiary sediments. The Pliocene-Pleistocene Trend extends approximately east and west in the South Central Gulf of Mexico Outer Continental Shelf. It is further from the Louisiana coast than from the Texas coast. Although there have been several shallow gas encounters relatively near the shoreline, the probability of encountering shallow gas is much higher in all areas south of these Trend lines especially in the High Island, South Marsh Island, and Eugene Island Areas (Figure 1).

The encounters with shallow gas flow studied in this report occurred during several different phases in the operations. Eight (30 percent) occurred while drilling was taking place, of which five occurred when the hole was drilled into a shallow gas pocket, and three involved drilling into an adjacent producing well. Thirteen (48 percent) of the gas flows were caused by swabbing actions and occurred while pulling drill pipe out of the hole. The swabbing in of a well may be caused by pulling the drill pipe out of the hole too fast or by a balled-up bit, or by a poorly-conditioned mud and hole. Because many Gulf of Mexico wells are drilled with low-weight fluids (gel muds having densities of 8.5-9.5 pounds per gallon) to prevent loss of drilling mud to

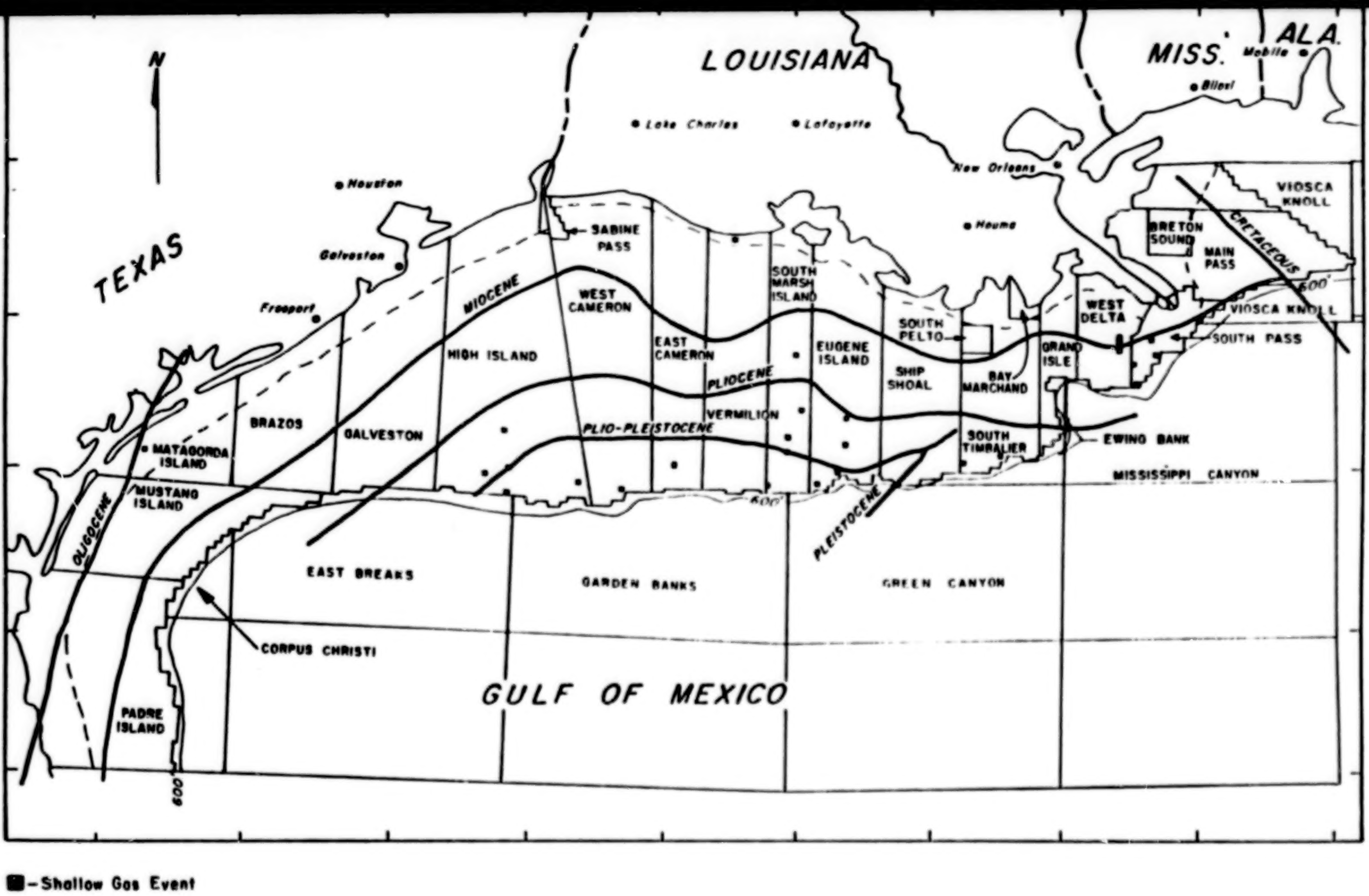

Figure 1 - Location of Shallow Gas Events on the Gulf of Mexico Outer Continental Shelf.

the shallow low-fracture gradient formations, the well bore/formation pressure ratio is usually only slightly greater than a balanced condition. A swabbing situation may produce an underbalanced hydrostatic condition which may cause an influx of formation fluids into the well bore when shallow gas zones are present.

Special attention needs to be given to cementing operations in potential shallow gas areas. Six (22 percent) of the shallow gas flows involved flow outside a string of casing and occurred during or immediately after surface casing cementing operations. One incident occurred during cementing, one occurred while washing out the casing annulus after cementing, three occurred while waiting on newly cemented casing to set, and one occurred while nippling down the BOP stack after cementing.

PREVENTIVE MEASURES AND RECOMMENDED ACTION

Preventive measures are necessary in planning drilling operations where shallow gas accumulations are probable. Abnormally pressured gas conditions exist in the Pliocene-Pleistocene Trend and elsewhere in the Gulf of Mexico. Special efforts are required to avoid drilling into these hazardous gas zones. Management should encourage and promote a cooperative effort of all personnel in planning the well, particularly if it is an exploratory well. Predrilling meetings should be held by engineering, geophysical, and geological personnel to coordinate and plan the drilling operations and select the most optimum drillsite. Prespud meetings should be held between lessee, operator, and contractor so that all personnel will be alert for signs of gas influx and be prepared to react properly if this situation develops.

The first step in selecting an optimum drill site to avoid shallow hazards is to acquire quality geophysical data for all proposed drilling locations and to identify any potential shallow hazards through the interpretation and evaluation of this data. The accuracy and availability of this seismic data is continuing to improve with advances in modern state-of-the-art technology. Avoiding a surface location where shallow gas is indicated may necessitate moving hundreds of feet and may require directional drilling to the target zone.

Gas seeps and surface faulting are additional indications of abnormally pressurized gas. However, the absence of gas seeps may indicate that whatever shallow gas exists could be trapped and accumulated under abnormally high-pressure conditions. Shallow gas accumulations may have migrated upward through fault planes to their present locations and may be present in structural traps as geopressurized gas. Additionally, shallow gas accumulations may be abnormally pressurized because of specific overburden pressure being reflected at a shallower depth because of closure or dip.

Even when the drill site selection has been made after careful interpretation of shallow hazards data, shallow gas kicks may still occur. Other recommended precautions are:

A. Drilling

1. The drilling rate should be controlled to prevent accumulation of gas in the annular mud, which could allow the well to flow, and adequate desanding and desilting equipment should be utilized to control the hydrostatic head in the annulus and prevent fracturing or lost circulation up the hole.

2. The mud pits should be continuously monitored while drilling the shallow portion of the well since a mud pit level increase is often the first indication of a kick.

3. If the well flow is diverted through the mud/gas separator accurate pressure gauges should be used to monitor both drill pipe and annular pressure in kill operations to prevent overpressure of the casing annulus. This could cause shallow formations to fracture below the casing shoe and allow well fluids to broach around the shallow casing strings, which may cause "cratering" and loss of the facility.

4. Many operators recommend that drill pipe floats be used to prevent backflow into the drill pipe and subsequent plugging when a gas flow is encountered.

5. Another factor to consider is the size of the hole to be drilled. There are advantages to drilling a 9 5/8-inch to 12 1/4-inch pilot hole instead of the standard 15- to 24-inch conductor and surface holes. Hole stability is increased, better open hole log quality is obtained, lower drilling fluid quantities are needed, and fewer solids separation problems are encountered when drilling pilot holes. Conversely, there are problems associated with smaller holes, such as rapid gas-to-surface time and greater potential for swabbing. However, if the well blows out, a smaller size hole has the tendency to bridge over more readily than a larger hole.

B. Pulling Drill Pipe

1. The well should be completely circulated and mud conditioned properly before tripping pipe to prevent swabbing. Before pulling drill pipe, indications of a balled-up bit or underbalanced mud weight conditions should be closely monitored.

2. If the above conditions are suspect, the drilling foreman or supervisor should be on the drill floor at all times while drill pipe is being pulled in the shallow part of the hole to detect any formation fluid influx and expedite control procedures.

3. While pulling pipe the well should be filled frequently and fillup volume closely measured to detect formation influx. If influx is noted, the drill pipe should be run back to bottom and the well circulated.

4. Every effort should be made to keep the loss of hydrostatic pressure in the well at a minimum, and if lost circulation is a problem this situation should be controlled before pulling out of the hole.

C. Running Drill Pipe

The drill pipe should be run into the hole at a rate that will minimize the fluid surge potential to avoid fracturing and subsequent lost returns. This situation could cause the well to flow from other reservoirs because of reduced hydrostatic pressures as the mud column falls.

D. Cementing

1. The mud should be adequately circulated and conditioned to insure that all cuttings are removed from the hole before cementing.

2. A lightweight, low-water loss cement should be used to prevent premature slurry dehydration, assure maximum cement strength, and prevent gas influx into the annulus.

3. The cement should be of adequate volume to insure proper cementing.

4. Accelerators should be used in the cement design to reduce the setting time and minimize gas influx into the annulus.

When shallow gas encounters occur, well control measures must be taken immediately. The relatively short "bottoms-up" time in drilling the shallow portion of the hole requires fast reaction, good judgment, and expedient operation by drilling personnel on the rig. Predrill planning in shallow gas control techniques regarding the sequences of control measures is a primary consideration. The following are some recommended immediate actions to take upon detection of a shallow gas flow with drill pipe in the hole:

Surface BOP (Jack-ups and Platform Rigs)

1. With Drive Pipe Installed - It is recommended that the well flow be immediately directed away from the rig through the available downwind diverter line(s). Mud (or seawater) should be pumped continuously to provide hydrostatic head to limit formation influx to minimize the volume of well solids in the flow stream. It may be necessary to cease pumping if gas accumulates around the facility and it becomes necessary to shut down the engines.

2. With Conductor Casing Installed - It is recommended that a well control plan be developed and made known to all personnel to assure an immediate response to a well flow situation. The plan should be to divert immediately through the available downwind system, or if a high-capacity mud/gas separator is available, route the well flow through it to maintain a mud supply for circulating purposes. In either case, the well should be circulated continuously with mud (or seawater, if necessary). Diverting through all available diverter lines should be considered if excessively strong well flow conditions develop and wind direction does not present a problem of gas accumulation around the rig.

Subsea BOP (Drill Ship or Semisubmersible)

1. With Structural Casing Installed - It is recommended that consideration be given to drilling conductor hole with returns to the seafloor in accordance with the provisions of Paragraph 5.4.2 of OCS Order No. 2. An exception to this would be drilling operations conducted in shallow water where the vessels buoyancy could be affected by surge and aeration of the water. In this case, shallow gas should be routed as recommended under Surface BOP (above) with plans made to quickly move the rig off location upwind/upcurrent.

2. With Conductor Casing Installed - It is recommended that equipment and procedures follow those previously discussed under Surface BOP, except that in deepwater the potential for riser collapse must be considered. It is recommended that operators consider using a valve near the bottom of the marine riser to allow seawater to enter the riser to help provide hydrostatic control. This is especially applicable to subsea operations where low formation fracture gradients may cause lost returns and seawater would replace well control fluids. An additional safety option of subsea operations is for the crew to shear the drill pipe, close in the well, release the riser, and move off location if gas flow becomes excessive around the vessel.

CHOICE OF DRILLING FACILITY

The type of drilling facility selected to drill a well in moderate water depths in potential shallow gas areas may be based on cost and availability, and not necessarily based on safety considerations. Many believe that bottom-supported rigs are best to use in shallow gas areas because a diverter system can be readily attached to the drive pipe before any drilling begins. A diverter system must be installed after conductor casing is set. Still others believe that floating-type vessels are preferred because they can be readily moved off location if a blowout occurs.

Problems are inherent in both types of drilling facilities. One drill ship was lost when the gas flow blew out around the drill pipe at the ocean floor and caused aeration of the water under the ship. This caused the ship to either flood from the water boil or lose buoyancy and sink. Many believe a diverter system tied into the structural casing may be a potential problem because the structural casing is not normally, firmly secured (not cemented) in the shallow subsurface. Other problems associated with riser evacuation which may develop in controlling a kick in conductor hole may occur using diverter systems. Therefore, in floating drilling operations, reference OCS Order No. 2, Paragraph 5.4.2, the operator may set the structural casing and drill conductor hole without the installation of a diverter system with mud returns to the seafloor. A plan to rapidly move the vessel off location should be in place. In five (56 percent) of the nine shallow gas flows involving floating drilling vessels, a diverter system was not installed at the time of the gas flow and one drill ship was lost. Of the other four encounters associated with floating drilling vessels having a diverter system installed, one diversion attempt was successful, two attempts were unsuccessful, and in one instance diversion was not attempted. A diverter operation is considered successful if the gas flow is contained and routed as designed by the diverter system [i.e., annular does not leak, lines do not leak or cut out, flow does not broach around casing string(s), and there is minimal damage equipment and personnel are not injured]. Even if the well bridges, sticks the drill string, and has to be plugged and abandoned, the operation is still considered successful.

DIVERTER SYSTEMS

A shallow gas diverter system is comprised of an assembly of valves and lines tied into the drilling spool or marine riser below an annular preventer. The system is designed to divert well flow safely away from the rig and personnel.

It is usually not desirable to restrict flow or stop flow completely when a kick is encountered while drilling the conductor or surface hole because of the risk of fracture around drive, structural, or conductor casing shoes in the unconsolidated sediments normally found in the Gulf of Mexico. This type of fracture and the resulting sustained upward flow around shallow casings has caused bottom-supported facilities to tip, settle, and/or eventually capsize because of the removal of the ocean floor sediments around the rig or platform legs. Two bottom-supported drilling facilities and one production platform were lost in this manner. The bottom-supported facility then loses lateral support and capsizes or settles into the crater formed by the blowout. From these examples it becomes obvious that diverter systems are necessary for the protection of personnel and equipment, especially in areas of probable shallow gas. A shallow well control technique to immediately divert through the downwind diverter line, while at the same time circulating a large volume of mud or seawater in attempting to control the formation influx, is generally believed to be excellent well control practice. The diverter system can be used to dissipate the flow by quickly exhausting the overpressured zone before a fracturing potential develops around the shallow casing. If the gas flow is relieved through an adequately-sized diverter system, the well may dissipate itself safely thereby saving the drilling facility and the well.

Of the 27 encounters cited in this report, 18 (67 percent) of the drilling rigs involved had a diverter system installed at the time of the gas flow. Of these 18, the installed diverter system was used successfully on 7 occasions (39 percent) and unsuccessfully on 11 occasions (61 percent). Three wells drilling conductor hole from a floating rig encountered shallow gas without a diverter system and moved off location successfully.

The causes of failure of the 11 unsuccessful diverter systems were as follows:

1. Overpressure - 5 times (45 percent)

   The well pressure and/or flow rate was too high for the diverter system to handle, causing diverter lines and/or other diverter system components to be destroyed.
2. Well Flow Broached Around Casing - 2 times (18 percent)
3. Inoperative Diverter Valves - 4 times (37 percent)

   The diverter valves would not open or were locked closed.

RECOMMENDATIONS

Many shallow gas diverter system failures may have been avoided if larger diverter lines had been used, sharp bends eliminated, and if lines had been properly anchored.

An adequate size for diverter lines and valves is a function of the pressure and volume of the gas, drilling mud, and formation solids to be diverted. It is generally believed that diverter lines 10 inches and larger in diameter are desirable because they can divert a greater volume of material in a shorter period of time with less back pressure on the formation and have less tendency to become plugged with gumbo and other formation solids. Most of the diverter systems on bottom-founded facilities in use today have lines 6 inches or larger. Most floating drill vessels have lines 10 inches or larger. Information gathered on diverter system configurations and discharge line diameters used in the Gulf of Mexico OCS was reported at the August 29, 1980, Regional Operations Technology Assessment Committee (ROTAC) meeting.

The following statistics were developed from this survey of over 160 rigs operating in the Gulf at that time:

Discharge Line Diameter	Percent of Rigs
10 inches and larger	16 percent
6 inches and 10 inches	67 percent
4 inches and to 6 inches	17 percent
Remote control valves	83 percent

The MMS recommends that the operator periodically test diverter valves for proper operation. Testing diverter valves and performing other preventive maintenance should increase diverter system performance and reliability and assure that the systems are operational when needed.

OCS Order No. 2, Paragraph 5.2, Subsea BOP Requirements (Note 4) and Paragraph 5.3, Surface BOP Requirements (Note 1) specify minimal installation requirements. After the effective date of Revised OCS Order No. 2, January 1, 1980, the previously-mentioned diverter system survey and shallow gas study was undertaken to determine the adequacy of the OCS Order requirements. This study of existing diverter systems on approximately 160 drilling rigs in the Gulf of Mexico, and an analysis of shallow gas events, indicated the need for additional precautions to be taken when drilling conductor and surface hole. A task group composed of personnel in the Gulf of Mexico Region of the Minerals Management Service recommends that the following precautions be addressed:

1. Lessee should submit plans, diverter schematic and operating procedure for the rig which will actually drill a well, with the Application for Permit to Drill (Form 9-331C).

2. When flexible diverter lines are used, end couplings should be installed as an integral part of the lines.

3. All diverter lines should be properly secured and should be as free from sharp bends as possible.

4. Only remote control, full-opening automatic diverter valves are recommended.

5. A daily functional or operational test of the diverter system should be performed by the operator, in addition to an operational test for flow through the diverter system before spudding all wells.

6. A minimum of one 12-inch or larger diameter diverter line with branch lines for downwind diversion capability should be used in subsea operations from a floating drilling facility.

7. A minimum of one 10-inch or larger diverter line, with branch lines for downwind diversion capability, should be utilized in bottom-founded drilling rig operations.

COST AND BENEFIT OF RECOMMENDATIONS

The strongest incentive for the lessee to seek better control of shallow gas encounters is the high costs associated with blowouts. These costs include millions of dollars in economic loss as well as numerous personal injuries and loss of human life. It is estimated that over $400 million in damage was caused by the 27 shallow gas encounters cited in this report in addition to the 28 lives that were lost.

Drilling and production equipment used in the OCS is very expensive. A typical offshore exploratory well costs from $1 million to $15 million in equipment, time, and labor. Present day replacement costs for a floating drilling vessel can range between $60 million and $70 million; a semi-submersible drilling rig between $80 million and $120 million; and a typical jack-up drilling rig in the Gulf of Mexico between $38 million and $50 million. Daily costs of drilling can exceed $100 thousand.

Likewise, replacement costs for a fully equipped production platform range from $100 million to $1 billion or more. As the search for new oil and gas moves into deeper and deeper water, exploration and production costs climb even higher. A state-of-the-art tension leg production platform designed for deep water is to be installed in late 1984, costing $1.2 billion.

During 27 shallow gas encounters discussed in this report, one drill ship was lost, two jack-up drilling rigs were lost, one production platform with drilling rig was lost, and three production platforms with rigs were extensively damaged. One platform with many producing wells was taken off production for months while wells were repaired and tests conducted to insure platform safety. Altogether, there were many months of drilling and production lost because of shallow gas encounters in the OCS. Besides these losses in equipment and drilling/production time, millions of dollars were spent to bring these blowouts under control.

The death toll from shallow gas blowouts has also been very high. Twenty-eight people have been killed and at least thirty-two more have been injured. It is impossible to put a dollar value on a human life; however, insurance companies have paid out millions of dollars to the families of those men who have been injured or killed because of blowouts.

Pollution and other adverse effects to the environment can be associated with shallow gas encounters. Pollution from the 27 blowouts cited in this report was minimal; however, it is possible for a major spill to occur if conditions are right. When a production platform collapses or catches fire, other producible wells on the platform, as well as storage tanks, separators, and fuel oil tanks, can become sources of pollution. Oil spill cleanup costs can be excessively high.

CONCLUSION

Encounters with shallow gas can be catastrophic, and the losses from such encounters can and have been very high. The best defense against shallow gas situations is to prevent the problem by avoiding a surface location where potential shallow gas hazards are indicated from seismic information. Additionally, all persons involved with the drilling operation should know what extra precautions should be taken while drilling the shallow portions of wells located in areas where shallow gas hazards are probable. Operators should use state-of-the-art diverter systems to aid in well control when drilling the upper portion of offshore wells. When shallow gas is encountered, reactions by all personnel must be immediate.

APPENDIX

SHALLOW GAS EVENTS

	Date	Block	OCS Lease	Well
1)	06-14-58	SP 27	0353	No. 25

ODECO Submersible drilling for Shell

The well was swabbed in while pulling the seventh stand of drill pipe out of the hole at a depth of 1896 feet. The well flowed out of control for five hours and then bridged over. Two people were injured. No other information is available on this accident.

2)	06-30-64	EI 273	0987	No. 4

Reading and Bates, C. P. Baker Drill Ship drilling for Pan American

Thirty-inch structural casing had been jetted to 305 feet (121 feet BML). Mud returns were being taken on the seafloor, and while drilling conductor hole a gas flow was encountered at 461 feet BML. The flow initially lifted a large amount of water into open doorways at the stern of the drill ship causing a severe change in trim and flotation, which resulted in the snapping of one bow anchor chain. Simultaneously, aeration of the water under the ship's stern by gas flowing from the well decreased buoyancy characteristics. The gas ignited, continued to burn, and the vessel sank. Twenty-two persons were killed, and twenty-three were injured. Gas continued to erupt and burn for 1 1/2 hours after the vessel sank. A diverter system was not installed for the drilling of this well. No hazard surveys were performed prior to drilling, and both the drilling vessel and the shallow well were a total loss.

3) 09-16-65 SM 48 0787 B-4

Gulf Platform Rig

While cementing the surface casing at 2,700 feet, the well blew out around the casing. The well flowed out of control for 6 1/2 months and bridged over on April 2, 1966. The platform settled 4 feet and damaged all the wells. Well B-4 was a total loss. A diverter system was not installed for the drilling of Well B-4.

4) 03-03-71 WC 639 G 2027 No. 2

ODECO Semi drilling for Sun

After circulating bottoms up with 9.4 ppg mud from a TD of 3956 feet, the drill pipe was started out of the hole. The well appeared to be dead, but when the third stand was pulled the well began to flow. The stand was lowered back into the hole, the kelly installed, and lower subsea (BOP) pipe rams closed. Annulus pressure was 675 psi and drill pipe pressure was 100 psi. The mud weight was increased to 10.3 ppg and drill pipe displaced. Shut-in annulus pressure increased to 725 psi, and drill pipe pressure was 0 psi. During an attempt to increase mud weight to 14 ppg, a gas boil 100 feet in diameter appeared approximately 150 feet off the port bow. Attempts to pump 14 ppg mud into the well while bleeding dry gas from the annulus through choke and kill lines were continued. All well control measures were unsuccessful and the rig was abandoned. The well bridged over in 3 days. There was no major damage to the rig, but the well was a total loss. A diverter system was not installed.

5) 12-03-72 SP 78 G 2185 No. 1

J. Storm No. 2 Jack-up drilling for Pennzoil

After drilling to 3,850 feet and circulating bottoms up, the drill pipe was started out of the hole before running surface casing. The hole would not take mud after pulling the 16th stand, and it was noted to be flowing. The stand was run back in the hole and the annular BOP was closed. Conventional kill operations were begun by circulating down drill pipe and out through the choke manifold. Gas bubbles were then seen breaking the surface about 60 - 80 feet from the location. The choke was fully opened, with no flow or pressure at the surface. Gas was then seen breaking out on both sides of the location. All personnel were evacuated, the gas ignited approximately 2 1/2 hours later, and shortly thereafter the rig collapsed into the water. Flames were reported as high as 100 feet above the water. The fire died out in several hours, but gas continued to boil until the well bridged 6 days later. A diverter had been installed but was not used. Rig and well were a total loss.

6) 12-11-73 SM 184 G 2295 No. 1

Santa Fe Bluewater No. 2 Semi drilling for Sun

Well No. 1 was spudded on December 9 in 322 feet of water. The 30-inch structural pipe was jetted to 540 feet (150 feet BML), a 26-inch conductor hole was drilled to 1210 feet (820 feet BML) with returns to the mud pit. The well started making gas and gas bubbles and mud appeared in the water around the rig. A TV camera was lowered to inspect the wellhead, but no indication of movement was noted. The bit was worked to 1210 feet and an attempt was made to pull out of the hole for a wiper trip. After pulling 5 stands of drill pipe, the well began flowing through the drill pipe and annulus. The drill pipe was then dropped and the rig moved off location. The well location was observed as gas bubbles slowly disappeared. The rig was pulled back to location and TV camera lowered to investigate the wellhead. No damage was noted to the guide base, structure, or casing, but 6 feet of scouring appeared about the wellhead. Drill pipe was retrieved, circulation established, hole reamed, and then conductor pipe was set at 1174 feet. The BOP stack and diverter lines were installed before drilling out the conductor shoe and drilling operations resumed. There were no further problems associated with the drilling of this well. There was no diverter system in use while drilling the conductor hole.

7) 04-18-74 SP 96 G 2188 No. 1

Glomar Grand Banks Drill Ship drilling for Exxon

While drilling 15-inch surface hole at 2379 feet, the well started to flow with considerable loss of mud from the riser because of expanding gas. The annular BOP was closed and the diverter valves were opened while circulating the well with kill mud and venting gas through the diverter. Both mud pumps were used to pump 11 and 11.5 ppg mud. In 1 1/2 hours, mud was being returned to the mud pits. The mud weight was then raised to 11.9 ppg and the well was brought under control in 4 hours. The well was logged, under-reamed, and 13 3/8-inch casing was set.

8) 06-10-74 EC 338 G 2063 A-6

Cactus 102 Platform Rig drilling for Sun

Drive pipe was driven to 560 feet (172 feet BML) and 16-inch conductor was set at 815 feet. At 5 a.m. on June 10, a 10 bbl mud loss was noted while drilling at 3,314 feet. A 35 bbl slurry of 10 ppg lost circulation material was spotted. Eighteen stands were pulled while filling the annulus with 40 bbl of mud and seawater. The well started flowing on the drill pipe side after the last 2 stands were pulled. The annular BOP was closed and an attempt was made to circulate the well through the choke, but with 272 bbl 10 ppg mud there was only gas returns. There was no diverter system on this rig. A bubble was observed 50 - 75 yards from the west side of the platform and increased to 50 feet in diameter. Twenty bbls of 12 ppg mud and 300 bbl of 14 ppg mud was pumped into the well, but dry gas continued to return through the choke line. When the mud supply was gone, seawater was pumped down the well. The platform was abandoned and the well bridged at 3:15 p.m. the next day.

9) 03-19-75 HI A-471 G 2690 No. 1

Zapata Topper III Jack-up drilling for Mobil

Drive pipe was driven to 490 feet (190 feet BML) and a 30-inch annular BOP with 6-inch diverter line(s) equipped with air-operated quick opening valves was installed. While drilling conductor hole at 753 feet, circulation was lost. The well was then conditioned and drilling continued to conductor casing depth of 1,150 feet with no further problems. After successfully running a deviation survey and while pulling the second stand, a mud flow was noted. The inside BOP valve was installed and both mud pumps were activated. The well began unloading from the annulus so the annular BOP was closed and both diverter valves were opened. The rig began to list slightly and all personnel were evacuated. When the location was observed 15 hours later, the rig had collapsed. The well bridged over about 6 days later.

10) 04-22-75 HI A-595 G 2721 No. 1

Santa Fe Mariner 2 Drill Ship drilling for Mobil

Thirty-inch structural pipe was jetted to 651 feet (110 feet BML) and 16-inch conductor casing was set at 1200 feet. A diverter system was installed that included a Regan diverter head, a 12-inch line, and air-operated, 12-inch diverter valves for 3-way diversion. While drilling at 2545 feet a kick occurred. The annular diverter on top of the riser was closed and the diverter lines were opened. The well pressure telescoped the riser slip joint, breaking the support arm, lifting the rotary table, and disconnecting the diverter line. The subsea BOP was closed and the well flow was routed through the choke line. Five hundred bbls of 11.5 ppg mud and 300 bbls of 10.2 ppg gel seawater was pumped. Pumps were switched to seawater when the mud supply was exhausted. Bubbles appeared off the port side of the ship, and within a half-hour the rig lost 5 to 6 feet of draft. The rig was winched 500 feet off location with anchor lines. After 2 days the gas boil was still approximately 120 feet in diameter.

11) 05-26-75 SP 61 G 2942 C-15

Platform Rig drilling for Atlantic Richfield

The 24-inch pipe was driven to 575 feet (293 feet BML) and 16-inch conductor casing was set at a depth of 1290 feet. While drilling the 13 1/2-inch surface hole for the 10 3/4-inch surface casing, the well was drilled into Well C-7 which was on gas-lift production. Well C-15 lost circulation into Well C-7 and then began to unload mud and lift gas. The annular BOP was closed and the diverters were opened. The well was successfully brought under control and then plugged with cement. A new well, Well C-18, was drilled through the Well C-15 drive pipe and completed at 12,881 feet.

12) 10-06-75 EI 327 G 2910 No. 3

Zapata Trader Drill Ship drilling for Oxy

Blowout preventers were being nippled down after cementing 13 3/8-inch casing at 4033 feet. Four hours later an annular gas flow occurred, and the drill ship was moved off location until the flow ceased (3 1/2 hours later). The BOPs were tested and a temperature survey and cement bond log were run. The casing shoe was then drilled out, tested, recemented, drilled out, and retested at 14 ppg equivalent. The well was successfully drilled to 7300 feet TD without further problems and subsequently completed. A diverter system was not installed at time of blowout.

13) 03-15-76 EI 380 G 2327 A-1

Marlin No. 5 Platform Rig drilling for Sun

After setting 10 3/4-inch surface casing at 2,716 feet and waiting on cement for 5 1/2 hours, the BOP and riser assembly were being nippled down. An annular gas flow occurred between the 10 3/4-inch and 16-inch casings. The platform had to be evacuated before the diverter system could be completely reinstalled. The downwind valve on the diverter line could not be opened when the wind changed and the diverter line cut out near the open valve. The flow lasted 16 days (dry gas) and died. Attempts to repair the well were unsuccessful, and the well was plugged and abandoned 21 days after the annular flow ceased.

14) 08-17-76 HI A-511 G 2694 A-4

Cactus 10 Platform Rig drilling for Sun

While making a wiper trip in the 13 1/2-inch hole at 2,735 feet, swabbing was noted on each of the 3 stands pulled. The fourth stand was worked up and down in an attempt to clear a balled bit, and then was run back in the hole to circulate. While connecting the kelly, the well began to flow. The mud pumps were started, diverter opened, and hydril closed. The well flowed some mud and then dry gas. The flexible vibrator hose on the diverter line parted and the well flow concentrated in the well bay area. The mud suction lines plugged and the pumps were switched to pumping seawater. The platform was abandoned shortly thereafter. The well flowed for an undetermined number of hours and ceased. The platform was damaged extensively, and the well was plugged and abandoned.

15) 01-16-77 SM 146 G 2591 A-4

Pool 452 Platform Rig drilling for Mesa

At 935 feet a short trip was made to condition the hole for 16-inch conductor casing. The well began to flow with four stands out of the hole. The diverter system was actuated and the platform was evacuated. Mud flowed out of the diverter for a few minutes and then ceased, and gas broached around the drive pipe. The flow ceased 3 hours later. The well was plugged and abandoned.

16) 07-06-77 SM 96 0791 No. 3

Transworld 61 Drill Ship drilling for Conoco

A 12 1/4-inch pilot hole was drilled to 4,730 feet and the subsequent I.E.S. log showed a 46 foot sand at 1,034 feet, with the top 10 feet being gas bearing. After cementing surface pipe at 4,707 feet and waiting on cement for 6 1/2 hours, the 20 3/4-inch BOP and riser were pulled. While running the 13 5/8-inch BOP stack 7 hours later, a gas bubble 40 - 60 feet in diameter was noted at the water surface and the drill ship was moved off location. A derrick barge was then used to set the BOP. Inspection showed the gas flow originated from the 13 3/8-inch casing annulus. The gas flow started on July 6 and continued until July 10. The well flow diminished to 5 percent of the original flow and was killed July 22. A cement bond log indicated a poor cement job above the gas sand. The 13 3/8-inch casing was perforated above the gas sand and squeezed with cement. A string of 9 5/8-inch casing was run to 4,655 feet and cemented. The well was eventually completed at 8,429 feet. It is believed that the original cement slurry had a high water loss which allowed a gas influx into the annulus. A diverter system was not installed at the time of the gas flow.

(17) 02-14-78 MI 664 G 3463 No. 1

Sea Drilling Netherlands No. 1 drilling for Transocean

Three and one-half hours after cementing 13 3/8-inch casing at 2,000 feet, an annular gas flow occurred. The flow was directed through the diverter system. The lessee attempted to close the diverters in order to move the rig, but was unable to do so against the pressure. The flow was continuous for approximately a day, and intermittent for another day. The surface well equipment above the annular preventer was cut off, the rig moved off location, and a derrick barge equipped to run drill pipe was installed adjacent to the well. The well was killed by pumping cement down the drill pipe, and was plugged and abandoned.

(18) 03-15-78 WD 79 G 1974 C-22

Cactus 164 Platform Rig drilling for Marathon

While drilling surface hole for Well C-22 at 1,694 feet, the bit drilled into the adjacent gas-lift well, Well C-6. The gas pressure from Well C-6 pressured Well C-22's annulus and blew the rotary bushings out. The diverters were opened and the annular BOP was closed. Personnel were evacuated and the flow soon ceased and the platform was reboarded 3 hours later. Well C-22 began flowing dry gas again 3 hours later, and seawater began to boil around the drive pipe. Three hundred bbls of 9 ppg mud were pumped down the drill string with no returns. The surface water began to boil higher, increasing from 8 to 10 feet. The platform was again evacuated and flow commenced uncontrolled through the conductor casing of Well C-22. The flow lasted 4 hours and then ceased. Well C-22 was plugged and abandoned. Platform damage was not substantial, and there was only one minor personnel injury.

19) 07-15-78 VR 23 G 2866 No. 12

Zapata Louisiana (No. 13) Platform Rig drilling for Mobil

The 30-inch pipe was driven to 248 feet, and the 20-inch conductor casing was set at 920 feet. After sidetracking at 2,400 feet, the well was drilled into Well No. 2 (gas well) at 2,495 feet. Well No. 12 began to flow and diverter valves were opened and the annular BOP was closed. A few minutes later both rubber hoses were blown from their swedge fittings, and the diverter valves were cut out by sand. The well bridged over within an hour. The well was later completed to 9,717 feet.

20) 09-04-78 HI A-551 G 3757 No. 1

Penrod 61 Jack-up Rig drilling for Pennzoil

The well had been drilled to 2,921 feet. While making a wiper trip before running a 13 3/8-inch surface casing, the well blew out at 5:45 p.m. The kelly was immediately picked up, the diverter valves opened, and the hydril closed. The diverter system contained 4-inch diverter valves with 6-inch diverter system lines. The flexible lines on the diverter parted, and the rig was evacuated. The well flowed for 2 hours and then bridged over. The rig was reboarded 24 hours later. The well was a total loss.

21) 06-01-79 WD 86 G 2934 No. 2

Dixilyn 370 Jack-up drilling for Marathon

Drive pipe was driven to 570 feet (339 feet BML), and conductor casing set at 979 feet. A surface hole was drilled to 4,035 feet, the hole was circulated with no problems, and surface casing cemented at 4,000 feet. One-inch pipe was run to wash out the 20 x 13 3/8-inch annulus between the casing strings. Three joints of the 1-inch wash pipe were removed when a sudden well flow from the annulus occurred. The diverter valves were opened, the annular BOP was closed and the rig evacuated. Gas and saltwater were diverted for 1 1/2 hours when a boiling action started on the water surface around the drive pipe. The well bridged over in 4 hours. There were no injuries to personnel or other damage, but the well was a total loss.

22) 03-24-80 HI A-368 G 2433 A-3

Pool 424 Platform Rig drilling for Pennzoil

Twenty-inch pipe was driven to 618 feet (178 feet BML), and the 16-inch conductor pipe was set at 1003 feet. The rig was drilling at a depth of 2505 feet when a decision was made to pull the drill pipe inside the conductor casing and repair the mud pumps. After five stands of pipe were pulled, the well started flowing mud through the annulus. One stand of pipe was then returned to the hole and the annular BOP was closed. The diverter valves would not open because they had been inadvertently locked closed with locking bars. While crew members were attempting to remove these locking bars, a diverter valve suddenly opened allowing gas pressure into a hose which ruptured and engulfed the rig floor and crew in a cloud of gas which quickly ignited. Six crew members were killed and twenty-nine were injured. The fire burned for 16 hours until the well bridged over. The well and platform were lost.

23) 12-27-81 SP 54 G 1606 No. 7

ODECO Ocean Scout Semisubmersible drilling for Texaco

The 30-inch structural casing was jetted to 601 feet and the 20-inch casing was set at 1,104 feet. While drilling a 12 1/4-inch hole, a gas pocket was encountered at 2,731 feet and the well began to flow. The annular BOP was closed but the overboard diverter valves would not open. The well pressure leaked around the BOP packing unit, the overboard diverter valves, and the flow line valve. All personnel were evacuated and the well bridged over within an hour. The well was later drilled to TD and completed.

24) 01-07-82 SM 130 G 2280 D-26

Movible No. 5 Platform Rig drilling for Shell

The well had been drilled to 979 feet through 24-inch drive pipe at 481 feet (168 feet BML). The well was circulated and a survey run. After pulling 5 stands of pipe, the mud pumps were engaged to fill the hole. While pulling the sixth stand, and with the mud pumps running, the well started flowing gas, water, and sand. The east diverter line was opened and annular BOP was closed. The drill pipe safety valve was installed, all engines shut down, and the platform abandoned. The well bridged over 12 hours later. The well was later drilled to TD and completed.

25) 05-14-82 ST 300 G 4240 A-5

Shell Rig Platform Rig drilling for Shell

The well had been drilled to 3,321 feet, with the 26-inch casing set at 1,362 feet. A trip out the hole was started to change the bottom-hole assembly. After 3 stands of pipe were pulled, the well began to flow. Two stands of pipe were run back into the hole, the diverter opened, and the annular BOP was closed. The flow was successfully diverted. The well either bridged or was killed with mud that had been pumped in the well within an hour of the initial flow. The well was later completed.

26) 10-21-82 EI 361 G 2324 A-10

Noble 24 Platform Rig drilling for Chevron

Gas-cut-mud problems were experienced on Well A-10 so the hole was conditioned for about 2 hours. The pipe was being pulled from 2493 feet before logging. The gas unit count increased after the last 6 stands of pipe were pulled into the casing. The well was circulated for 45 minutes, but then began to kick. One stand of pipe was run in the hole and the annular BOP closed. The well flowed through the mud-gas separator until the 6-inch line ruptured. The overboard diverter valve would not open and the annular BOP failed; well control was lost and the platform was evacuated. The well caught fire 10 hours later, destroying the drilling rig, quarters, and other buildings. The fire was extinguished 3 days later, and the well bridged over. The well was plugged and abandoned.

27) 04-09-83 ST 264 G 5209 No. 2

Keyes 301 Jack-up Rig drilling for Champlin

Conductor casing (20-inch) was set at 1205 feet with full cement returns. While drilling at 3377 feet an increased flow at the flow line occurred. Mud weight was raised from 9.8 to 10.8 ppg while the well was being circulated. Gas increased and mud was kicking through the rotary table after 4 hours of circulating; and the diverter system was activated. Mud circulation was continued until the supply was exhausted, and then seawater was pumped in at a rate of 12 bbls per minute. Diversion continued while mixing 1600 barrels of 11 ppg kill mud which was pumped in and killed the well. Drilling was resumed and at 3436 feet a saltwater flow was encountered causing mud to kick over the rotary and it was necessary to divert again. Diversion continued and mud pumps were switched to the 12 ppg kill mud in the reserve pits and the well was successfully killed again. Sixteen-inch casing was run and cemented after remedial work on the well bore at 2180 feet. The diverter system worked successfully for approximately 14 hours and the well was saved.

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